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Arizona Corporation Commission

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BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

DOCKET NO. E-00000A-02-0051

IN THE MATTER OF THE GENERIC
PROCEEDINGS CONCERNING ELECTRIC
RESTRUCTURING ISSUES.

IN THE MATTER OF ARIZONA PUBLIC
SERVICE COMPANY'S REQUEST FOR
VARIANCE OF CERTAIN
REQUIREMENTS OF A.A.C. R14-2-1606.

DOCKET NO. E-01345A-01-0822

IN THE MATTER OF THE GENERIC
PROCEEDING CONCERNING THE
ARIZONA INDEPENDENT SCHEDULING
ADMINISTRATOR.

DOCKET NO. E-00000A-01-0630

IN THE MATTER OF TUCSON ELECTRIC
POWER COMPANY'S APPLICATION FOR
A VARIANCE OF CERTAIN ELECTRIC
COMPETITION RULES COMPLIANCE
DATES.

DOCKET NO. E-01933A-02-0069

IN THE MATTER OF THE APPLICATION
OF TUCSON ELECTRIC POWER
COMPANY FOR APPROVAL OF ITS
STRANDED COST RECOVERY.

DOCKET NO. E-01933A-98-0471

Citizens Communications Company's Comments to Staff's List of Track B Issues

1 Pursuant to the First Procedural Order on Tract B Issues dated June 20, 2002,
2 Citizens Communications Company ("Citizens Communications"), hereby files comments
3 to Staff's List of Track B Issues ("List of Issues") filed on May 31, 2002. Specifically,
4 Citizens Communications supports Staff's recognition, as described in ¶ 5A, for the need
5 to evaluate the disposition of a utilities purchase power adjustment clause within Tract B
6 proceedings. Citizens Communications believes purchase power adjustment clauses are a
7 threshold issue, especially for transmission-dependent companies like Citizen
8 Communications.

9 Adjuster mechanisms, including Purchase Power Fuel Adjuster Clauses ("PPFAC")
10 have been a long standing regulatory rate-making tool which have been supported by the
11 Commission and the Courts. Because purchased power is the single largest expense for
12 generating electricity, such mechanisms allow the pass through of uncontrollable costs
13 without impacting the utilities revenue requirement, thereby avoiding the continual need to
14 file rate cases.

15 Such issues are especially significant to Citizens Communications because as a
16 transmission-dependent UDC under a regulated standard offer service requirement, it has
17 the obligation to serve and provide such service to its customers in its service areas. Due
18 to the recent events and concerns in the electric industry as well as the inherent difference
19 among the utility companies, Citizens Communications contends that both generic and
20 company specific discussions are needed. Therefore, Citizens Communications proposes
21 that these issues should be included in Track B workshops.

22 Citizens Communications requests that the Commission take notice of the testimony
23 previously filed by Mr. Carl W. Dablestein in the above-captioned Docket and attached to
24 the docketed copies as Exhibit A.

25 Further, Citizens Communications would like to add these issues for Track B.
26

- 1 1. How may transmission dependent utilities ("TDU's") in transmission constrained
- 2 areas effectively participate in a competitive solicitation process?
- 3 2. How may a load serving distribution company ("LDC") with long term power
- 4 purchase agreements to serve its load and load growth effectively participate in a
- 5 competitive solicitation process?
- 6 3. Will local generation be considered a viable option to transmission imports?
- 7 4. Will a LDC in a transmission constrained area be allowed to include self generation
- 8 in its rate base?
- 9 5. How are the costs of transmission additions to eliminate constraints to service in a
- 10 TDUs' service area to be recovered?
- 11 6. How are duplicative costs associated with providing adequate transmission import
- 12 capability to serve all the load in an LDCs' service area to be avoided?
- 13 7. How will federal transmission and generation facilities be effectively integrated into
- 14 a competitive power supply model?
- 15

16 Citizens Communications further requests that the Commission take notice of the testimony
17 previously filed by Resal Craven in the above-captioned Docket and attached to the
18 docketed copies as Exhibit B.

19
20 RESPECTFULLY SUBMITTED this 28th day of June, 2002.

21 **CHEIFETZ & IANNITELLI, P.C.**

22
23 By 

24 Steven W. Cheifetz
25 Robert J. Metli
26 Attorneys for Citizens
Communications Company

1
2 Original and ten (10) copies of the foregoing
3 filed this 28th day of June, 2002, with:

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22 All parties of record on the service list

23
24 By 

25 F:\CLIENTS\Citizen Communications\Electric Restructuring Docket\Corporation Commission\CC Comments to Staff's Track B Issues 06 26 02 kk.doc

Exhibit A

INTRODUCTION

Q. Please state your name and address

A. My name is Carl W. Dabelstein. My business address is 2901 North Central Avenue, Suite 1660, Phoenix, Arizona 85012

Q. By whom are you employed and in what capacity?

A. I am employed by Citizens Communications Company ("Citizens" or "Company") in the Rates and Regulatory Section of its Public Service Organization.

Q. Please state your professional qualifications.

A. A description of my education and professional qualifications is attached hereto as Appendix A.

Q. What is the purpose of your testimony?

A. On October 18, 2001, Arizona Public Service Company ("APS") submitted an application to the Arizona Corporation Commission ("ACC" or "Commission") containing a request for a partial waiver of the requirements of Rule R14-2-1606(B) of the Arizona Administrative Code. That Rule would otherwise obligate APS to acquire all of the power to serve its standard offer customers from the competitive market, with at least 50% obtained through a competitive bidding process. As more fully explained in that filing, the APS is proposing to supply a majority of the power to standard offer customers from affiliated generation sources. One element of the proposed pricing methodology included in the APS proposal is the reinstatement of its purchased power and fuel adjustment clause.

1 Q. Why does the APS proposal affect Citizens?

2 A. The APS waiver request generated a significant response and questions
3 relating to the Commission's electric restructuring rules from a variety of
4 affected parties. Between January 14, 2002 and February 7, 2002, each of
5 the three Commissioners docketed letters expressing their opinions and
6 seeking information pertaining to Arizona electric restructuring. On March
7 22, 2002, the Commission Staff issued a Staff Report containing summaries
8 of the interested parties' responses to the Commissioners' questions and
9 specific recommendations that certain issues to be addressed in the generic
10 restructuring docket. Included among the recommendations was Staff's
11 position that there is a need to reassess the feasibility of adjustor
12 mechanisms in connection with the provision of standard offer service in a
13 restructured electric industry in Arizona.

14
15 Q. Why are you addressing the issue at this time?

16 A. A Motion of Arizona Public Service Company for Determination of Threshold
17 Issue was filed by APS on April 19, 2002. The stated intent was to obtain
18 Commission decisions on certain critical threshold questions concerning the
19 direction that the ACC intended to take in connection with retail electric
20 competition. Included as part of a "Proposed Procedural Plan" was a brief
21 discussion about adjustor mechanisms and APS' stated belief that specific
22 adjustor mechanisms should be considered in utility-specific proceedings.

23
24 On April 23, 2002, the Commission Staff filed its response to the APS
25 Motion in which it states:

26 Adjustor Mechanisms and the specifics of Retail Direct
27 Access and shopping credits are ultimately essential to a

1 functioning competitive market, but need not be addressed
2 with finality at the outset. [Page 4, line 17.]
3

4 On May 2, 2002, the Chief Administrative Law Judge issued a procedural
5 order calling for testimony on "Track A Issues" to be filed by noon on May
6 29, 2002. The procedural order also identified "Track B Issues" as those
7 dealing with competitive solicitation of power supplies. No testimony filing
8 schedule for Track B issues was included in the procedural order. It is not
9 completely clear whether Adjustment Mechanisms are to be considered as a
10 Track A Issue for which testimony is currently being sought. They were not
11 specifically listed in the procedural order, however, as more fully explained
12 later in my testimony, they are fully consistent with the concept of standard
13 offer service, and have a very significant role in preserving the financial
14 integrity of Citizens by affording the Company an opportunity to recover its
15 cost of service. Accordingly, I am submitting this testimony on the
16 Adjustment Mechanism issue that supports the continuation of the PPFAC
17 for standard offer service.
18

19 Q. What if the Administrative Law Judge or Commission did not intend to
20 address Adjustment Mechanisms as part of Track A?

21 A. If the hearing officer or Commission does not intend to include Adjustors in
22 the scope of this current inquiry into the generic issues of electric
23 restructuring, I respectfully request that this testimony be accepted and be
24 preserved for incorporation into the record at the appropriate time.
25

26 Q. Please summarize your testimony.

27 A. Adjustment Mechanisms, particularly the Purchased Power and Fuel
28
29

1 Adjustment Clause ("PPFAC"), used by electric utilities, and the Purchased
2 Gas Adjustment ("PGA") mechanism, used by local gas distribution
3 companies, are a useful regulatory tool that benefits both the respective
4 utilities and their customers. PPFACs and PGAs have been used by utilities
5 in Arizona for decades. As long as the existing host utilities retain the
6 obligation to be the provider of last resort, and must render standard offer
7 service to customers that do not want to procure power from competitive
8 suppliers, the PPFAC should remain in effect, particularly with respect to
9 generation-dependant utilities such as Citizens. The same rationale that led
10 to the introduction of the PPFAC more than fifty years ago continues to
11 apply to standard offer service in a restructured electric industry in Arizona.
12

13 **ADJUSTMENT MECHANISMS**

14 Q. What is an adjustment mechanism?

15 A. An adjustment mechanism is a widely-used standard tariff provision,
16 generally formula-based and pre-approved by regulators, that enables
17 utilities to automatically adjust rates to reflect experienced changes in
18 specified elements of cost of service, over which the affected company can
19 exercise little control. Their use as a regulatory tool can be traced as far
20 back as World War I. They are consistent with the fundamental tenet of
21 the traditional regulatory compact that allows a utility the opportunity to
22 recover all reasonable and necessary cost of providing service.
23

24 Q. What is the purpose of an adjustment mechanism?

25 A. The objective of an adjustment mechanism is to allow the utility to recover
26 certain types of increased costs and to provide a means for customers to
27 benefit from cost reductions, outside of a full rate case hearing, which is
28
29

1 both expensive and time-consuming. By their very nature, adjustment
2 mechanisms, when correctly administered, do not affect the profitability of
3 the entity. Instead, they simply allow the utility to "pass-through" the costs
4 to customers on a dollar-for-dollar basis.

5
6 Q. What types of costs are covered by adjustment mechanisms?

7 A. Although virtually any component of the cost of service may be covered by
8 adjustment mechanisms, by far the predominant use of adjustors is for
9 tracking variations in the cost of fuel and purchased power by electric
10 utilities and the cost of gas supply by local natural gas distribution
11 companies. That is largely because those costs are typically the single
12 largest operating expense for that type of utility.

13
14 Q. How does an adjustment mechanism work?

15 A. Within the context of a general rate case, a basing point must be
16 established. With respect to energy utilities, that is typically defined as the
17 "base cost of power" or "base cost of gas" that is included in the usage
18 rates being set, and represents a per unit (i.e. ccf, therm, or kilowatt-hour)
19 charge reflective of the test year cost level included in the overall revenue
20 requirement. The base cost becomes the benchmark for administration of
21 the adjustment mechanism.

22
23 As the new service rates approved in the rate case go into effect, each
24 month, the differences between that actual expenditures made for the
25 designated cost and the amounts being recovered for that cost through the
26 base cost component of the usage portion of customer bills must be
27 computed and tracked. That is generally accomplished with the use of a

1 special tracking account or "Bank" account, a regulatory asset added to the
2 utility's balance sheet. Expenditures for the cost being tracked are
3 recorded as a charge to the Bank account as they are incurred. At the end
4 of the month, an amount equal to the costs billed to and recoverable from
5 customers (computed as the product of sales quantities and the base cost)
6 is removed from the Bank account and charged to operating expenses. The
7 amount billed in rates to cover the specific cost that is included in revenues
8 is the same as the amount reflected in recorded operating expenses,
9 thereby producing no profit margin. That is the key objective of
10 adjustment mechanisms. The balance residing in the Bank account at
11 month-end represents the cumulative over or under-recovery of costs
12 associated with the designated expense item. When the Bank balance
13 reaches a predetermined level, the utility is then allowed to implement a
14 surcharge to recover un-recovered costs, or implement a surcredit to pass
15 on any cost savings to customers. Once the adjustor is implemented, the
16 Bank accounting procedure previously described is modified to also consider
17 amounts billed or credited each month via the new adjustor.

18
19 Q. What if there was no adjustor mechanism?

20 A. As stated, adjustor mechanisms generally are used only for the types costs
21 over which the utility can exercise little control. Without an adjustor
22 mechanism, the respective utility would only recover the test year cost
23 level implicit in the revenue requirement underlying service rates. If the
24 actual costs incurred are greater, the utility's investors would have to
25 absorb the incremental costs. If the actual costs are lower, the Company's
26 customers would be denied the cost savings. The absence of an
27 adjustment mechanism creates potentially significant earnings volatility

1 because a small change in the cost of fuel, purchased power or natural gas
2 can produce significant changes in profitability. That equates to higher
3 earnings volatility and business risk, and correspondingly higher costs of
4 capital that must be reflected in revenue requirements and customer rates.

5
6 Q. What are the benefits of having an adjustment mechanism such as the
7 PPFAC or PGA?

8 A. The advantages usually cited include:

- 9 • They allow the utility to recover increases in certain types of costs
10 over which they have little or no control.
- 11 • They permit savings in the tracked cost to be passed on to
12 consumers.
- 13 • They eliminate the time and costs (for both the utility and its
14 regulators) associated with would otherwise be more frequent general
15 rate cases.
- 16 • They allow the utility to change prices in a timely manner so that they
17 are more reflective of the cost of service, thereby sending the proper
18 price signals to consumers.
- 19 • They tend to stabilize earnings and reduce financial risk, which
20 translates into lower costs of capital to be recovered in service rates.

21
22 **ADJUSTOR MECHANISMS IN ARIZONA**

23 Q. When were adjustor mechanisms introduced as a regulatory tool in
24 Arizona?

25 A. The Commission has used the PPFAC and PGA for decades. The
26 Commission first permitted the use of an adjustment clause in 1942, when
27 a predecessor to what is today Tucson Electric Power Company ("TEP") was
28
29

1 given authority to pass through fluctuations in the cost of its gas purchases.
2 Adjustment clauses addressing changes in Arizona electric companies' cost
3 of fuel first appeared in 1952. ACC Decision No. 26996 authorized a supply
4 cost pass-through for APS in December of that year, and Decision No.
5 27040 granted a fuel cost adjustor for Citizens.
6

7 Q. Has the Commission ever analyzed or reconsidered whether a PPFAC was
8 still appropriate?

9 A. Over the years, the PPFAC has been evaluated and reconsidered on a
10 number of occasions.
11

12 In September 1978, the ACC issued Decision No. 49333, which essentially
13 terminated the existing PPFAC mechanisms because of the Commission's
14 perception that fuel supplies and prices, as well as the economy, were
15 sufficiently stable, thereby negating the need for the adjustor. Such action
16 produced numerous motions for reconsideration from the various affected
17 parties to the proceeding. On October 25, 1978, the Commission issued
18 Decision No. 49438 abrogating the previous Decision and granting the
19 motions for rehearing. It reinstated the PPFAC, albeit in a slightly different
20 form, and directed the Utilities Division to develop the appropriate reporting
21 forms and filing requirements. The Companies' ability to automatically
22 change the PPFAC factor was replaced by a requirement that formal hearing
23 before the Commission must be held in connection with any such change.
24 Decision No. 49576, issued on December 29, 1978, identified and directed
25 the use of such reporting requirements and reaffirmed the Bank account as
26 an integral part of the PPFAC. That Decision also contained a new
27 requirement that a change in the cost of fuel and purchased power
28
29

1 exceeding one mill per kilowatt-hour would trigger a hearing to determine
2 whether the PPFAC adjustor should be changed.
3

4 In September 1979, the ACC issued Decision No. 50266 that allowed the
5 electric distribution cooperatives in the State to adjust their PPFAC factors
6 in the month following receipt of purchased power invoices without formal
7 Commission approval. The Decision also required the co-ops to submit
8 certified audits of power supply costs and adjustments annually.
9

10 The continuing use of the PPFAC as a regulatory tool was again considered
11 by the Commission in 1986, in connection with an APS rate application and
12 request for an accounting order. A key issue in that proceeding was
13 whether the APS PPFAC (and by implication that of other electric utilities)
14 should be terminated or, if not, substantially changed or modified. In its
15 Decision No. 55118, issued in July of 1986, the Commission found that
16 abolishing the PPFAC at that time would:

- 17 • likely result in an increase in APS' cost of capital;
- 18 • prevent APS' customers from benefiting from lower fuel and
19 purchased power costs; and
- 20 • lead to a possible reduction in the attention paid to fuel and
21 purchased power issues, since the examination thereof would then be
22 buried in the numerous other issues raised in any general rate case.
23

24 Decision No. 55118 also reaffirmed the Commission's position that power
25 supply costs are largely beyond the Company's control, that such costs
26 comprise a significant portion of operating expenses, that even a small
27 change in such costs can have a material effect on earnings, and that a
28
29

1 PPFAC mechanism helped to avoid the need for frequent, repeated rate
2 cases.

3
4 Q. Has the PPFAC been considered in other forums in Arizona?

5 A. Yes, it was addressed in Opinion No. 71-15 issued by the Arizona Attorney
6 General in May 1971, in response to the questions of whether the
7 Commission has jurisdiction to authorize use of such an adjustment
8 mechanisms, and what procedures must be observed when a mechanism is
9 approved initially. In concluding that such adjustment mechanisms were
10 permissible under the Constitution and statutes of the State, the Attorney
11 General opined that for a PPFAC to be properly included in a utility's tariff, it
12 must first have been introduced and approved within the context of a
13 general rate proceeding.

14
15 The Attorney General's Opinion was also supported in the frequently cited
16 *Scates* Decision, issued by the Arizona Court of Appeals in 1978. That case
17 established the current prohibition against single-issue ratemaking by the
18 Commission. Because adjustment mechanisms such as the PPFAC and PGA
19 are intended to be profit neutral, they are considered as an allowed
20 exception; thus, once established, a Fair Value determination is
21 unnecessary in connection with subsequent changes in the adjustor rates.

22
23 Most recently, adjustment mechanisms were considered by the Arizona
24 Court of Appeals in its March 2001 decision involving Rio Verde Utilities.
25 The Court overturned a Commission Decision allowing the utility to
26 implement a cost pass-through mechanism without first being approved in
27 the context of a general rate case in which Fair Value was determined.

1
2 Q. Has the Commission recently considered adjustment mechanisms?

3 A. Yes. In 1998, there was a formal inquiry into the Purchased Gas
4 Adjustment mechanisms that were being used by the local distribution
5 companies in the State. After two winter seasons of numerous customer
6 complaints about spikes in gas prices largely attributed to the deregulation
7 of the natural gas industry, the Commission directed the Staff to initiate an
8 inquiry to examine the existing PGA and determine what changes might be
9 made. At that time, the PGA methods were not uniform between the
10 various companies. The overriding objective of the inquiry was to develop
11 changes to the PGA that would lead to rate stability.
12

13 Q. What was the outcome of that inquiry into the PGA?

14 A. On October 30, 1998, the Commission issued Decision No. 61225 that
15 reaffirmed the continuing value of the PGA as a regulatory tool, and
16 adopted a new, uniform methodology to be followed by all companies. That
17 inquiry into the PGA mechanism represents the most recent indication of
18 the Commission's philosophy with respect to the use of a pass-through
19 mechanism to recover the costs of a commodity where price is influenced
20 by the volatility of deregulated wholesale markets.
21

22 Q. Have any Arizona utilities discontinued the use of their PPFACs or PGAs?

23 A. Yes, in the late 1980s, the PPFACs for both APS and TEP were discontinued.
24 On April 13, 1989, the Commission issued Decision No. 56450, terminating
25 the APS PPFAC, based on its finding that fuel prices were stable and were
26 expected to continue being so for the next several years. On June 22,
27 1989 the Commission issued Decision No. 56526, terminating the PPFAC of
28
29

1 TEP because the Commission determined that TEP had intentionally
2 manipulated the Bank balance.

3
4 **CITIZENS' PPFAC**

5 Q. What has been Citizens' experience with respect to the PPFAC?

6 A. As previously stated, Citizens' Arizona Electric division has had an
7 adjustment mechanism in place since 1952 when it was given fuel cost
8 pass-through authority by the Commission. In February 1967, the
9 Commission issued Decision No. 38826, permitting Citizens to pass through
10 changes in its purchased power supply costs.

11
12 Over the years, the PPFAC has worked well in protecting the interests of
13 both the Company and its customers. When there was an under-recovery
14 of costs in the PPFAC Bank, Citizens was permitted to implement a
15 surcharge intended to recover the shortfall within six to twelve months.
16 When an over-recovery existed in the Bank, either refund checks were
17 issued, or a surcredit was reflected on customers bills to return the excess
18 within a relatively short time period. Recently, however, as I will explain
19 more fully below, Citizens has encountered increases in the cost of
20 purchased power that have resulted in the Bank balance reaching
21 unprecedented levels, while Citizens awaits an opportunity to be heard and
22 a Commission decision on a requested PPFAC surcharge.

23
24 Q. Please describe Citizens' power supply arrangements.

25 A. To serve its approximately 77,000 customers residing in Mohave and Santa
26 Cruz Counties, Citizens obtains power under a seven-year contract with
27 APS that was effective in June 2001. The power is transmitted from APS

1 generating facilities to Citizens' service areas on transmission facilities
2 owned and operated by the Western Area Power Administration ("WAPA").
3 The current agreement with APS provides for a fixed rate of 5.8 cents per
4 kilowatt-hour and applies to all of Citizens' Arizona power requirements.
5

6 For emergency back-up purposes in Santa Cruz County, the Company has
7 in place approximately 48 megawatts of combustion turbine generating
8 capacity at its Valencia facility in Nogales. These units may use either
9 natural gas or oil as the generating fuel.
10

11 Q. What base cost of power is included in Citizens' current electric service
12 rates?

13 A. In Decision No. 59951, issued in January 1997, in connection with the last
14 general rate case, the Commission established \$.05194 per kilowatt-hour
15 as the base cost of power for the Arizona Electric Division. That is
16 comprised of \$.04802 for power supplied by APS and \$.00392 for
17 transmission service provided by WAPA.
18

19 Based on the final adjusted test year costs reflected in the revenue
20 requirement underlying service rates, power supply costs represent 68% of
21 total operating expenses and 61% of the total revenue requirement. Power
22 supply is clearly the largest cost of providing electric service.
23

24 Q. Since that base was established, what has been Citizens' cost of power
25 supply for its Arizona Electric Division?

26 A. As indicted on Schedule No. 1, the monthly power supply cost has range
27 from a low of \$.03940 to a high of \$.26609 per kilowatt-hour.
28
29

1
2 Q. Please describe Citizens' PPFAC?

3 A. Citizens' PPFAC is designed to track both the cost of purchased power
4 (including charges from both APS and WAPA) and the cost of fuel used for
5 generation at the Valencia facility in Santa Cruz County. Differences
6 between the actual costs of power and fuel and the amounts recovered in
7 rates are maintained in the PPFAC Bank, a regulatory asset on the
8 Company's balance sheet. When the applicable trigger point is reached,
9 the Company may seek Commission approval to either implement a
10 surcharge or surcredit, or to issue refund checks as appropriate.
11

12 Q. What is the trigger point for Citizens' PPFAC?

13 A. Commission Decision No. 62094, issued on November 19, 1999,
14 established a trigger point of \$2.6 million. That represents the monetary
15 equivalent of the one mill per kilowatt-hour standard that was previously
16 used.
17

18 Q. Specifically, what is required when the trigger point is reached?

19 A. When that Bank balance level is reached, Citizens is required to either:
20 • File for a PPFAC rate adjustment within 45 day of determining that
21 the threshold will be exceeded; or
22 • Contact Commission Staff to discuss why a PPFAC rate adjustment is
23 not necessary.
24

25 Q. What are the current reporting requirements for Citizens' PPFAC?

26 A. In accordance with the requirements of Commission Decision No. 49576,
27 Citizens files four standard schedules on behalf of its Arizona Electric
28
29

1 Division each month with the Commission. These include Schedule FA-1,
2 which is an analysis of the activity in the PPFAC Bank for the current
3 month; Schedule FA-2, which is a summary of fuel and purchased power
4 costs for the month; Schedule FA-3, which is a statistical report showing
5 sales, revenues, and customer numbers by rate class for the reporting
6 month; and Schedule FA-4, a six-month forecast of fuel and purchased
7 power costs and Bank balances. A copy of Citizens' most recent monthly
8 PPFAC report to the Commission accompanies this testimony as Schedule
9 No. 2.

10
11 Q. Please explain the events that led to Citizens' current PPFAC filing before
12 the Commission.

13 A. Under the previous power supply agreement with APS, the monthly charges
14 to Citizens included the incremental costs incurred when APS had to
15 procure power in quantities in excess of its own resource capabilities.
16 During the summer months of the year 2000, APS had to acquire significant
17 amounts of power from the wholesale market. The average cost to Citizens
18 ranged from \$.11463 to \$.17524 per kilowatt-hour. At the end of the
19 summer, the PPFAC Bank had an under-recovered balance in excess of \$50
20 million.

21
22 In September 2000, Citizens filed an application with the Commission
23 seeking approval of a surcharge that would recover the Bank balance over
24 a period of three years. In the ensuing months, Citizens conducted as
25 lengthy analysis of the APS bills and began exploring alternatives to the
26 existing power supply agreement. In the meantime, the surcharge
27 application remained in limbo.

1
2 Q. What was occurring in the wholesale power markets when citizens
3 renegotiated its power supply agreement?

4 A. While power supply costs returned to more reasonable levels during the
5 Fall-Winter-Spring months of 2000-2001, the price spikes returned in May
6 of 2001, producing an average supply cost in excess of twenty-six cents per
7 kilowatt-hour. In July 2001, Citizens signed a new power supply agreement
8 with APS that was intended to remove the volatility in the price of power.
9 The new agreement would provide all of Citizens' power supply
10 requirements at a fixed cost of for of 5.8 cents for a period of seven years.
11

12 Q. What is the magnitude of the recovery that Citizens is currently seeking in
13 its PPFAC docket?

14 A. During the summer of 2001, the PPFAC Bank continued to grow. In
15 September 2001, Citizens filed an amended application that updated the
16 reported Bank balance, which had grown to \$94 million detailed the terms
17 of the new power APS supply agreement, and revised its surcharge request
18 to propose a recovery period to coincide with the seven-year contract term.
19

20 Even though the new contract with APS provides much-desired price
21 stability, Citizens is still experiencing a shortfall in cost recovery leading to
22 a continuing growth in the PPFAC Bank balance to unprecedented levels.
23 After factoring in the effect of line losses, the new 5.8 cent APS is
24 equivalent to a rate of 6.5 cents at the customers' meters. When compared
25 with the 4.8 cents base cost of APS power implicit in current rates, there is
26 a shortfall of 1.7 cents per kilowatt-hour.
27

1 The PPFAC application has not yet been set for formal hearing. Citizens has
2 requested that a hearing be scheduled for this September.

3
4 Q. Has Citizens opened its service territory for retail electric competition?

5 A. No, it has not, however some clarification is appropriate. In the spring of
6 2000, a settlement had been reached between Citizens, the Commission
7 Staff and RUCO that would provide for the opening of our service territory
8 within four months after Commission approval of the agreement. The
9 settlement agreement contained specific methods for quantifying stranded
10 costs, which included the PPFAC Bank balance. At the time, that balance
11 was relatively small, and the price spikes that occurred during the summer
12 of 2000 were not anticipated.

13
14 In June of 2000, testimony in support of the settlement was filed by the
15 parties and a formal hearing was conducted. As the parties awaited the
16 issuance of a proposed order, Citizens began receiving the APS power bills
17 reflecting the very high power costs. Soon, it became clear that the
18 computational methodology agreed upon for stranded costs recovery would
19 be rendered administratively infeasible due to the ever-increasing PPFAC
20 Bank balance. After filing the surcharge application in September 2000,
21 Citizens filed a motion to reopen the record regarding the settlement
22 agreement. A procedural conference was held on November 20th at which
23 the parties agreed that the Commission could not effectively consider the
24 settlement until the matters contained in the PPFAC surcharge application
25 were resolved.

26
27 On January 18, 2001, the hearing officer issued a procedural order

1 suspending the settlement process until the PPFAC matter is concluded.
2 Citizens remains committed to opening its Arizona service territory to retail
3 electric competition.
4

5 **RECOMMENDATIONS**

6 Q. Should the PPFAC mechanism be retained?

7 A. Yes it should, particularly for generation-dependent utilities such as Citizens
8 and the distribution co-ops. Under the Commission's Rules, host utilities
9 retain the obligation to serve as a provider of last resort and are required to
10 provide standard offer service. The PPFAC mechanism should continue for
11 such companies' standard offer service. The mechanics of its
12 administration should be evaluated basis of the relevant facts and
13 circumstances of each company. I would agree that, in evaluating the
14 continuing feasibility of the PPFAC, the Commission should consider the
15 changes that have occurred in the electric power industry in recent years.
16

17 Q. What is the significance of your emphasis with respect to generation-
18 dependent utilities retaining the PPFAC?

19 A. Public utility profitability is a function of the rate base and rate of return
20 implicit in the revenue requirement underlying service rates. By definition,
21 generation-dependent utilities do not have investment in electric production
22 facilities; thus, there is no profit element associated with the generation
23 function in their service rates. There is no margin for changes in power
24 supply costs. Absent a PPFAC, increases in such costs must be absorbed by
25 the utility's investors, while customers will never benefit from power cost
26 reductions. That creates a risk, which translates into higher costs of capital
27 for the affected company.
28
29

1
2 Q. Is the PPFAC compatible with retail electric competition?

3 A. Yes. The PPFAC is totally consistent with the provision of standard offer
4 service after the introduction of retail competition. The traditional
5 justification for a PPFAC will continue for standard offer service. Many
6 customers will opt for standard offers service because they wish to maintain
7 the status quo or do not want to assume the risks that might be perceived
8 with a switch to competitive power suppliers.
9

10 Q. Should the PPFAC apply to customers that procure their own power
11 supplies?

12 A. No. Customers that opt to procure their own power supplies should
13 recognize that, along with the potential benefits, there might be
14 unanticipated costs and other additional risks. Customers that leave their
15 host supplier, prospectively, should neither benefit from the PPFAC nor
16 incur any power supply cost other than those resulting from their own
17 purchase decisions.
18

19 Q. What if customers opt for alternative power suppliers at a time when the
20 PPFAC Bank has an un-recovered balance.

21 A. Unrecovered PPFAC Bank balances are a stranded cost. The Commission's
22 Rules clearly recognize the propriety of stranded cost recovery. Customers
23 that switch suppliers should be responsible for their share of stranded
24 costs; otherwise, there exists a perverse incentive for customers to switch
25 and leave remaining customers or the utility's investors left holding the
26 bag.
27

1 Q. Has the Commission specifically addressed this issue?

2 A. Yes, it has with respect to the PGA Bank. Citizens' Arizona Gas Division has
3 in place a special transportation tariff under which customers meeting
4 certain criteria may procure their own gas supplies while continuing to use
5 the Company's distribution facilities for delivery. That is essentially the
6 same scenario that will exist with the introduction of retail electric
7 competition. Recognizing the potential for stranded costs in the PGA Bank,
8 the Commission approved language in the gas transportation tariff that
9 allows the Company to compute the share of the existing PGA Bank balance
10 attributable to any customer at the time of switching from full service to
11 transportation service, and to recover that amount from the respective
12 customer in twelve monthly installments. I am not necessarily
13 recommending that same methodology for recovering costs in the PPFAC
14 Bank when customers opt for other power suppliers under retail
15 competition; I am only illustrating that the Commission has recognized the
16 potential for and propriety of recovering balances in the Bank that may
17 become stranded upon the departure of customers.

18
19 Q. What would the impact on Citizens be if the PPFAC mechanism was not
20 retained?

21 A. As previously described, Citizens is essentially a generation-dependent
22 electric utility. Without the PPFAC, its only source of power supply cost
23 recovery would be the through the base cost of power implicit in service
24 rates. Under-recoveries would have to be absorbed by the Company's
25 investors, while customers would never benefit from cost savings that may
26 occur. Undoubtedly, given the relative significance of power supply costs to
27 the Company total revenue requirement, the frequency and number of rate

1 cases would accelerate.
2

3 Q. Do you have an example to demonstrate the effect on Citizens if the PPFAC
4 were eliminated?

5 A. Yes, Schedule No. 1 is a comparison of actual monthly power supply cost
6 with the base cost of power, beginning with January 1997, when current
7 service rates went into effect, through February 2002. As indicated on the
8 Schedule, during that period comprising sixty-two months, the actual
9 monthly costs were lower than the base cost twenty-five times and higher
10 forty-five times. Absent the PPFAC, on a cumulative basis, customers
11 would have been denied costs savings of approximately \$11.2 million.
12 Notwithstanding the current PPFAC application before the Commission, and
13 absent general rate case filings, Citizens would have had no means by
14 which to recover approximately \$106.3 million in higher power supply
15 costs.
16

17 Without the PPFAC, there most assuredly would have been additional
18 general rate cases filed. Rate cases require the time and financial
19 resources of the utility, the Commission, the Staff, and RUCO. Customers
20 are also affected. The earnings volatility that would exist in the absence of
21 a PPFAC would also contribute to a perception of significantly greater
22 financial and business risks resulting in higher costs of capital to be
23 recovered in service rates.
24

25 Q. Why would the cost of capital be higher if the PPFAC were discontinued?

26 A. It is generally acknowledged that there is a strong correlation between
27 earnings volatility and uncertainty and the perceived risk associated with
28
29

1 any investment. Investors base their required rates of return on
2 expectation and perceptions of risks and prospects for a given firm. Being
3 risk adverse, investors expect to be compensated for increased risk through
4 higher returns.

5
6 As previously stated, power supply costs, particularly for a generation-
7 dependent utility, are a significant portion of the total revenue requirement.
8 A small change in power supply costs can produce a substantial change in
9 earnings. Absent an adjustment mechanism, such as the PPFAC, the
10 volatility of earnings will be significantly greater. Such volatility, along with
11 the resulting perceived greater investment risk, will incent investors to
12 demand higher rates of return. That will be accomplished either through
13 increased costs of fixed income securities being imposed upon the utility, or
14 the bidding down of the market price of its publicly traded common stock.

15
16 Q. What is your specific recommendation to the Commission?

17 A. I strongly recommend that the PPFAC be retained for application in
18 connection with the required provision of standard offer service. Consistent
19 with the finding of the Commission in the 1998 PGA inquiry that there is an
20 economic cost associated with the Bank balances, electric companies should
21 be allowed to accrue and recover carrying charges on the balances.

22
23 Because of the changes that have occurred in the electric utility industry
24 during the past few years, I believe that it would be appropriate to consider
25 the broader, conceptual issues of the PPFAC in the context of a generic
26 proceeding. Issues to consider include the effects of financial derivatives
27 and other hedging tools used in connection with fuel and power supply, and
28
29

1 the costs of complying with the Environmental Portfolio Standard. In the
2 meantime, the existing PPFACs should remain in effect.

3
4 The more complex and unique fuel and power supply issues associated with
5 entities possessing their own generation resources should also be
6 considered on a company-specific basis, in a general rate case setting.

7
8 Q. What if the Commission were to decide to eliminate the PPFAC for all
9 customers?

10 A. First, based on the legal and regulatory history of the PPFAC, which I have
11 previously described, I believe that such action could only be done in
12 connection with a general rate case. Balances in the PPFAC Banks existing
13 at the time of the elimination would have to be addressed and some means
14 of recovery or refunding be established. The likely effect on the cost of
15 capital would have to be determined. Finally, the Commission would have
16 to reassess the manner by which the power supply costs of the affected
17 utility are to be reflected in revenue requirements, including consideration
18 of the use of projected cost data.

19
20 Q. Do you have any other recommendations?

21 A. Yes, I believe that there should be a continuation of some form of deferred
22 accounting for fuel and power supply costs.

23
24 Q. Please explain that additional recommendation.

25 A. Without the PPFAC, and unless some method of addressing un-recovered
26 power supply costs is developed, a utility will effectively bear a disallowance
27 for any such costs incurred above the base amount established in service

1 rates. I believe that both the utility and its customers will benefit with a
2 continuation of the deferral accounting method that has traditionally existed
3 in connection with the PPFAC. In connection therewith, the Company would
4 continue to charge all power supply costs to a special deferred account and
5 transfer to expense only the amount being recovered in revenues. The
6 account balance would accumulate for regulatory consideration in a future
7 rate case.

8
9 Q. What would be the benefits of a continuation of deferral accounting?

10 A. The utility would benefit by lower costs of capital, than would otherwise be
11 the case, due to the reduction in potential earnings volatility and loss.
12 Customers would benefit because any savings in power supply costs would
13 be preserved for their benefit.

14
15 Q. How would your deferral accounting proposal affect the Commission's
16 oversight role?

17 A. It would have no effect. The Commission would retain regulatory control
18 over power supply cost recovery. All reasonable costs in the deferred
19 account balance would be recoverable, while any costs found by the
20 Commission to be unreasonable or imprudently incurred would be
21 disallowed.

22
23 Q. What are the regulatory accounting implications associated with your
24 deferred accounting proposal?

25 A. The applicable accounting standard is Statement of Financial Accounting
26 Standards No. 71, *Accounting for Certain Types of Regulation* ("SFAS 71").
27 The standard applies to regulatory assets, generally defined as

1 expenditures that would otherwise be required to be charged to expense,
2 but instead are capitalized for future rate recovery. Under SFAS 71, such
3 costs may be capitalized if:

- 4 • If it is probable that future revenue in an amount at least equal to the
5 capital cost will result from inclusion of that cost in rates, and
- 6 • Based on available evidence, the future revenue will be provided to
7 permit recovery of the previously incurred cost rather than to provide
8 for expected levels of similar future costs. **If recovery is through**
9 **an automatic adjustment clause, regulatory intent must**
10 **be clearly indicated.** (Emphasis added)

11 The Commission's historical treatment of PPFAC Bank balances has
12 provided the necessary degree of assurance of future rate recovery to
13 comply with the requirements of SFAS No. 71. If the deferral accounting is
14 continued as I recommend, and appropriately acknowledged by the
15 Commission, the ability to report such regulatory assets in conformity with
16 the accounting standard should remain unchanged.

17
18 Q. Does that conclude your testimony?

19 A. Yes it does.
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APPENDIX A

PROFESSIONAL QUALIFICATIONS

Q. What is your educational background?

A. I graduated from the University of Nebraska with a Bachelor of Science Degree in Business Administration, major in Accounting. I also received a Master of Business Administration Degree, concentration in Finance from Rockhurst College in Kansas City, Missouri.

Q. What has been your professional experience?

A. Upon graduation from college in 1968, I was employed by the international public accounting firm Arthur Andersen & Co. in its Omaha office. During such employment, I participated in and directed audits and other engagements involving commercial banks, healthcare facilities, public utilities, insurance carriers, and other clients.

In 1971, I accepted a position reporting to the controller at Central Telephone & Utilities Corporation at its then headquarters in Lincoln, Nebraska. During the five years I was employed by CTU, I directed such activities as financial and regulatory accounting and reporting, internal auditing, budgeting, corporate acquisitions and divestitures, rate cases and other regulatory filings, banking relations, and corporate financings.

From 1976 to 1981, I was employed by Kansas City Power & Light Company. My responsibilities included the corporate audit function, operations budgeting, and rate case filings in Kansas and Missouri and with the Federal Energy Regulatory Commission. During that period, I also

1 served as a member of the Missouri Valley Electric Association, and the
2 Finance and Accounting Committee of the Standardized Nuclear Unit Power
3 Plant System.

4
5 From 1981 to 1991, I was employed as a Senior Project Manager for a
6 regulatory consulting firm and successor firm, directing rate case,
7 management audit, litigation support, and other engagements for a
8 clientele that included utility companies, utility regulatory agencies, and
9 intervenors in regulatory proceedings.

10
11 From 1991 through 1996, I was employed as an internal consultant with
12 Northern States Power Company in Minneapolis. My responsibilities
13 included accounting, taxation and cost allocation issues in rate cases and
14 special regulatory proceedings, performing capital investment evaluations,
15 accounting and tax research, developing cost recovery plans, and advising
16 senior management in connection with the development of performance-
17 based ratemaking proposals and strategic policies for a successful transition
18 to a competitive electric utility industry.

19
20 In late 1996, I accepted a position as Tax Research Coordinator for Tucson
21 Electric Power Company. My chief responsibilities included tax research and
22 planning, preparation and review of corporate tax returns, and meeting with
23 representatives of tax authorities. I also served on the corporate planning
24 team addressing industry deregulation and competitive issues, and also
25 directed the team charged with responsibility for creating and implementing
26 a system for strategic business units, and developing the associated
27 accounting and financial reporting practices.

1
2 In January 1997, I was appointed Director of Utilities for the Arizona
3 Corporation Commission. In that capacity, I directed a staff of
4 approximately ninety professional and clerical employees responsible for
5 overseeing railroad and pipeline safety in Arizona and for regulating the
6 water, telephone, electric, and natural gas distribution utilities in the State.
7

8 I accepted my current position with Citizens Utilities in February 1998. In
9 that capacity, I coordinate regulatory activities in the states served by
10 Sector utilities. In addition, I am a member of the Arizona Utility Tax
11 Issues Group and previously served on the Arizona Corporation
12 Commission's Water Utility Task Force and PGA Working Group.
13

14 Q. What are your professional certifications and affiliations?

15 A. I hold Certified Public Accountant Certificates issued by the respective
16 Boards of Accountancy in Nebraska and Kansas. I am a member of the
17 American Institute of Certified Public Accountants, the National Association
18 of Radio and Telecommunications Engineers ("NARTE"), and the National
19 Association of Railroad and Public Utility Tax Representatives.
20

21 Q. What technical licenses do you hold?

22 A. I hold an Advanced Class FCC Radio License and a Technician Class NARTE
23 certification with regulatory and antennas endorsements.
24

25 Q. What is your teaching experience?

26 A. I have developed and conducted seminars on a variety of topics for
27 employees of public utilities, regulatory agencies, and consulting firms.
28
29

1 Since 1993, I have been a member of the faculty of the NARUC Regulatory
2 Studies Program at the Public Utility Institute at Michigan State University.
3 For the past two years I have been an instructor at the Western Utility Rate
4 School, jointly sponsored by NARUC and the Center for Professional
5 Development at Florida State University. I have also taught classes on
6 behalf of the U.S. Telephone Association. In connection with my teaching, I
7 have written three instructional books: *Public Utility Income Taxation and*
8 *Ratemaking, Public Utility Working Capital, and Generally Accepted*
9 *Accounting Principles for Utilities.*

10
11 Q. What has been your experience in regulatory proceedings?

12 A. During the past thirty years, I have participated in numerous rate cases
13 and other regulatory and litigation proceedings involving electric, gas
14 transmission and distribution, telephone, water, and wastewater utilities
15 conducted in Alaska, Arizona, California, Colorado, Connecticut, District of
16 Columbia, Florida, Hawaii, Illinois, Indiana, Kansas, Maryland, Minnesota,
17 Missouri, Nevada, New Mexico, North Carolina, North Dakota, South
18 Dakota, Vermont, Virginia, and Wisconsin, as well as proceedings before
19 the Federal Energy Regulatory Commission and the National Energy Board
20 of Canada. I have also spoken before legislative bodies in connection with
21 proposed legislation. I have testified on matters involving financial and
22 regulatory accounting and reporting, auditing, cost allocation, financial
23 forecasting, capital and operations budgeting, taxation, corporate
24 acquisitions, holding companies, valuation and transfer pricing,
25 deregulation, the cost of capital, industry restructuring, and regulatory
26 policy.

Exhibit B

INTRODUCTION

Q. Please state your name and business address.

A. My name is Resal A. Craven. My business address is Citizens Communications Company, 2901 N. Central Avenue, Suite 1660, Phoenix, AZ 85012.

Q. By whom and in what capacity are you employed?

A. I am employed by Citizens Communications Company ("Citizens") as Director of Engineering for its Arizona Electric Division.

Q. What are your duties and responsibilities at Citizens?

A. I am responsible for providing overall direction for the permitting, right-of-way acquisition, design and construction of transmission and substation facilities. I am also responsible for the negotiation and administration of transmission service contracts for delivery of electric power to Citizens' operating districts in Arizona, providing technical assistance to Citizens' district engineers concerning engineering, construction and contractual matters for distribution-system projects and assisting with power supply arrangements.

Q. Briefly describe your education.

A. I earned a BSEE from North Carolina State University, Raleigh, N.C. and have subsequently attended classes and professional courses on power system engineering and management.

Q. Would you please describe your professional affiliations?

A. I am a Registered Professional Engineer and a Senior Member of the

1 Institute of Electrical & Electronics Engineers ("I.E.E.E.").

2 Q. Briefly describe your work experience.

3 A. I have thirty-eight years' experience in engineering & engineering
4 management with electric utilities, specializing in transmission &
5 distribution systems planning, design and construction in transmission and
6 power supply contract negotiation and administration.

7
8 Q. Have you previously testified?

9 A. Yes. I have testified before the Arizona Corporation Commission, the
10 Louisiana Public Service Commission, the Federal Energy Regulatory
11 Commission, and in federal district court on matters regarding electric
12 transmission systems and contracts.

13
14 Q. What is the purpose of your testimony?

15 A. The purpose of my testimony is to describe the effects of the Arizona
16 Corporation Commission's ("Commission") Rule 14-2-1609 (B) on
17 transmission dependent Utility Distribution Companies (UDCs) and on the
18 cost of service to retail customers in the UDC's service area. I will also
19 recommend revisions to the Rule.

20
21 Q. Arizona Corporation Commission Rule R14-2-1609 (B) mandates that the
22 UDC shall retain the obligation to assure that adequate transmission import
23 capability is available to meet the load requirements of all distribution
24 customers within their service areas. What is your assessment of the
25 impact of this Rule on the UDCs?

26 A. This requirement puts an undue economic burden on customers in the
27 UDC's service area.

1 Q. Why is this so?

2 A. My comments address the direct effects of the Rule on Citizens
3 Communications Company's Arizona Electric Division. Citizens is a
4 transmission-dependent utility and owns no transmission facilities of its own
5 that allow import of power into its service area. All transmission import
6 capability is provided by contracts with wholesale transmission providers.
7 The only transmission owner in Citizens' service area, and with whom
8 Citizens has transmission interconnections for wholesale power, is the
9 Western Area Power Administration ("WAPA"). WAPA is the federal power
10 marketing agency that sells power from federal resources to eligible entities
11 and markets excess transmission capacity to eligible wholesale purchasers.
12 Citizens obtains all of its transmission service to import power to serve the
13 load in its service area from WAPA under two basic transmission contracts.
14

15 Q. Please describe the contracts.

16 A. One contact is for service over the Parker-Davis Transmission System.
17 That contract is for firm transmission service through February 28, 2008,
18 from defined points of receipt to defined points of delivery. It was signed
19 prior to the issuance by FERC of Order Nos. 888 and 889 regarding
20 transmission access. The points of receipt are located at WAPA's 230 kV
21 bus at Pinnacle Peak Substation near Phoenix, Arizona, and at WAPA's 115
22 kV bus at Saguaro Substation near Tucson, Arizona. The principal points of
23 delivery are at Hilltop Substation near Kingman, Black Mesa Substation
24 near Lake Havasu City, and the Nogales Switchyard southeast of Tucson.
25 Under this contract, an annual capacity reservation is made on a rolling
26 three-year basis. Citizens is obligated to pay the annual reservation costs
27 in 12 equal payments. The amount of reserved capacity cannot be reduced
28
29

1 until the fourth year (i.e. reservations made for the 2002 operating year
2 cannot be reduced before 2005.) One of the terms in the contract, which
3 dates back to 1987, provides that if Citizens is not using its reserved
4 capacity, then WAPA has the exclusive right to use it. Therefore, under this
5 contract, there is no possibility of Citizens selling any unused reserved
6 capacity to others.

7
8 The second transmission contract is for firm point-to-point service over the
9 Pacific Northwest – Southwest Intertie Project. This contract was signed in
10 June 2001, and provides a specific amount of capacity (110 MW) for a
11 specific term (through June 30, 2011). The defined point of receipt is at
12 the same Pinnacle Peak Substation previously described, except that it is on
13 WAPA's 345 kV bus. The defined point of delivery is WAPA's 230 kV bus at
14 its Griffith Switchyard southwest of Kingman. Citizens is obligated to pay
15 the annual reservation costs for transmission capacity in 12 equal payments
16 each year for the term of the contract. Under this contract, if Citizens is
17 not using its reserved capacity, and there is a willing buyer, Citizens may
18 resell it.

19
20 Q. How is Citizens adversely affected by Rule R14-2-1609 (B)?

21 A. As written, Rule R14-2-1609 (B) obligates the UDC to assure that adequate
22 transmission import capability is available to meet the load requirements of
23 all distribution customers in its service area. However, it has no provisions
24 that require coordinated planning of delivery capacity from resources to
25 load and places no requirement on Competitive Scheduling Coordinators
26 ("CSC's") or competitive energy providers to participate with the UDC for
27 planning transmission improvements or in mitigating the cost associated
28
29

1 with changes in transmission use. Because Citizens' existing transmission
2 contracts to import power into its service area are all long term contracts,
3 from defined points of delivery to defined points of receipt, the contract
4 path is usable in only one direction, and only between those points of
5 receipt and points of delivery. The defined points of receipt into WAPA's
6 systems were established to import power purchased by Citizens initially
7 from Arizona Public Service Company ("APS") and now from Pinnacle West
8 Capital Corporation ("PWCC") with whom Citizens has an all requirements
9 contract. While the contracts worked well for that purpose, they do not
10 provide the flexibility needed to accommodate changed usage patterns.
11

12 Q. Is it true that the Affected Utilities are required to provide a pro-rata share
13 of the their transmission capacity to Competitive Scheduling Coordinators
14 who want to serve load in their service area?

15 A. Yes. Commission Rule R14-2-1609 (A) provides that any transmission
16 capacity that is reserved for use by the retail customers of the Affected
17 Utility's UDC shall be allocated among standard offer customers and
18 competitive market customers on a pro-rata basis. Citizens would be
19 required to allocate a pro-rata share of its WAPA transmission contract to
20 CSC to comply with the rule. WAPA has agreed that Citizens can assign a
21 portion of its contract path, on a recallable basis, to third parties for
22 delivery to loads served under retail competition in Citizens' service area. A
23 copy of a letter received from WAPA, dated July 12, 2001, (Exhibit A) on
24 this subject is attached. However, to use Citizens' contract path the CSC
25 would have to include one of the defined points of receipt in Citizens'
26 contract as a part of the path from its resource(s) to the load in Citizens'
27 service area.
28
29

1 Q. Is that practical?

2 A. I do not believe it is likely to happen. The energy provider would have to
3 be PWCC or some other company having a network transmission service
4 agreement with APS, and APS would have to have available firm
5 transmission capacity from the resource to the point of receipt, or the CSC
6 would have to arrange an alternate path to Citizens point of receipt. For
7 imports into Mohave County, Citizens' point of receipt is Pinnacle Peak 230
8 kV, and for imports into Santa Cruz County it is Saguaro 115 kV.
9

10 Q. Could a CSC arrange an alternate transmission path with WAPA that is not
11 covered by an existing contract with Citizens so they could they serve load
12 in Citizens' Service Area?

13 A. Yes, they could.
14

15 Q. How would that impact Citizens' transmission arrangements?

16 A. Citizens would be directly impacted in two ways:

- 17 1. Because Citizens already has long term contracts for transmission
18 service from defined points of receipt, it is obligated to pay for that
19 contracted capacity whether it has customers to serve or not. To the
20 extent that Citizens' customer load is reduced when retail competition
21 is introduced, the average cost of transmission to serve Citizens
22 Standard Offer customers will increase.
- 23 2. The amount of import capacity cannot be reduced for two reasons.
24 First, under Rule R14-2-1609 (B), Citizens retains the obligation to
25 provide adequate import capability to serve all distribution customers
26 within its service area. As a result, Citizens is required to keep the
27 contracts whether it has a customer or not. Second, under Rule R14-
28

1 2-1606 (A) the UDC (Citizens) must provide Standard Offer Service
2 and act as provider of last resort; thus, also requiring Citizens to keep
3 the contracts, whether or not it is serving customers.
4

5 Q. Is Commission approval required for a contract between a CSC and WAPA
6 to serve load in Citizens' service area?

7 A. No. WAPA is not subject to the Commission's jurisdiction. It is my
8 understanding that, if WAPA received a request from a CSC to provide
9 transmission service to one of Citizens' points of delivery, the Commission
10 lacks jurisdiction and authority to prevent them from doing so.
11

12 Q. What would be the impact on Citizens if the CSC's resource is one of the
13 new Independent Power Producer ("IPP") plants in Mohave County?

14 A. As previously explained, Rules R14-2-1609 (B) and 14-2-1606 (A) require
15 Citizens to procure the transmission input capacity necessary to serve all
16 distribution customers in its service territory. Under Citizens' existing
17 contracts, no provisions exist for redesignation of contact paths or short-
18 term reduction of contract capacity. However, the actual number of
19 customers served by Citizen would be reduced, resulting in an increase in
20 the average per customer cost of transmission import capacity.
21

22 Q. Do you have a suggestion on how the rules regarding transmission can be
23 modified to resolve the problems you have identified?

24 A. Yes. I recommend that the rules be modified as follows:

- 25 • CSC's be required to utilize the same transmission paths as are
- 26 available to the UDC.
- 27 • If the available paths are insufficient to meet the needs of the CSC,
- 28
- 29

1 there should be a formal process for the CSC to request alternate
2 transmission service.

- 3 • A mechanism should be developed whereby the cost of such service,
4 including stranded transmission costs, would be paid for by the CSC.
- 5 • CSCs should be prohibited from by-passing the distribution utility and
6 arranging alternative transmission source without also assuming the
7 cost related to such action. A part of such costs includes the pro rata
8 share of costs associated with the requirement that the Distribution
9 Company be the provider of last resort for Standard Offer Service.
- 10 • Any customer opting for alternative power supplies should be
11 responsible for his share of any unrecovered power supply costs prior
12 to his departure, and any additional costs his departure continues to
13 impose on Citizens.

14
15 Q. Do you have suggested language for the modified rules?

16 A. Yes. Specifically, Rule 14-2-1609 B should be modified as follows:

- 17 B.1 Utility Distribution Companies shall retain the obligation to assure
18 that adequate transmission import capability is available to meet the
19 load requirements of all distribution customers within their service
20 areas. Utility Distribution Companies shall retain the obligation to
21 assure that adequate distribution system capacity is available to meet
22 the load requirements of all distribution customers within their service
23 areas.
- 24 B.2 Competitive Scheduling Coordinators shall be required to utilize the
25 same scheduling paths for imports into a Utility Distribution
26 Company's service area as the Utility Distribution Company. If such
27 paths are inadequate to meet the needs of the Competitive

1 Scheduling Coordinator, then the Competitive Scheduling Coordinator
2 shall make a transmission service request to the Utility Distribution
3 Company for alternate or increased import capability into the Utility
4 Distribution Company's service area. The Competitive Scheduling
5 Coordinator shall be responsible for the cost of providing the
6 requested service, including the Utility Distribution Company's
7 stranded costs associated with its provider of last resort obligations.
8 Rights to any resulting increase in transmission import capability into
9 the Utility Distribution Company's service area shall be conveyed the
10 to the Utility Distribution Company in their entirety.

11 B.3 Individual customers switching to competitive energy service shall be
12 obligated to the respective UDC for their share of any amounts
13 residing in the purchased power bank that relate to periods before
14 their departure for standard offer service.

15
16 Q. Does this complete your testimony?

17 A. Yes.
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